3.0 ALTERNATIVES

3.1 FACTORS USED IN SELECTION OF ALTERNATIVES

3.1.1 Alternatives Development and Screening Process

One of the most important aspects of the environmental review process is the identification and assessment of reasonable alternatives that have the potential for avoiding or minimizing the impacts of a proposed Project. In addition to mandating consideration of the No Project Alternative, the California Environmental Quality Act (CEQA) Guidelines (section 15126.6(d)) emphasize the selection of a range of reasonable alternatives and an adequate assessment of these alternatives to allow for a comparative analysis for consideration by decision-makers.

The CEQA requires consideration of a range of reasonable alternatives to the Project or project location that: (1) could feasibly attain most of the basic project objectives; and (2) would avoid or substantially lessen any of the significant impacts of the proposed Project. An alternative cannot be eliminated simply because it is more costly or if it could impede the attainment of all project objectives to some degree. However, the State CEQA Guidelines declare that an Environmental Impact Report (EIR) need not consider an alternative whose effects cannot be reasonably ascertained and whose implementation is remote or speculative. The CEQA requires that an EIR include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed Project.

This screening analysis does not focus on relative economic factors of the alternatives (as long as they are feasible) since the State CEQA Guidelines require consideration of alternatives capable of eliminating or reducing significant environmental effects even though they may “impede to some degree the attainment of project objectives or would be more costly.” Likewise, the question of market demand or project need is not considered.

3.1.2 Alternatives Screening Methodology

Alternatives to the proposed Project were selected based on the input from Venoco, the EIR preparers, and the public and local jurisdictions during the EIR scoping hearings. The alternatives screening process consisted of three steps:

Step 1: Define the alternatives to allow comparative evaluation.

Step 2: Evaluate each alternative in consideration of one of more of the following criteria:

- The extent to which the alternative would accomplish most of the basic goals and objectives of the Project;
- The extent to which the alternative would avoid or lessen one or more of the identified significant environmental effects of the Project;
- The potential feasibility of the alternative, taking into account site suitability, economic viability, availability of infrastructure, General Plan consistency, and consistency with other applicable plans and regulatory limitations; and
- The requirement of the State CEQA Guidelines to consider a “no project” alternative and to identify, under specific criteria, an “environmentally superior” alternative in addition to the “no project” alternative (State CEQA Guidelines, section 15126.6(e)).

Step 3: Determine suitability of the proposed alternative for full analysis in the EIR. If the alternative is unsuitable, eliminate it, with appropriate justification, from further consideration.

Feasible alternatives that did not clearly offer the potential to reduce significant environmental impacts and infeasible alternatives were removed from further analysis. In the final phase of the screening analysis, the environmental advantages and disadvantages of the remaining alternatives were carefully weighed with respect to potential for overall environmental advantage, technical feasibility, and consistency with project and public objectives.

If an alternative clearly does not provide any environmental advantages as compared to the proposed Project, it is eliminated from further consideration. At the screening stage, it is not possible to evaluate potential impacts of the alternatives or the proposed Project with absolute certainty. However, it is possible to identify elements of the proposed Project that are likely to be the sources of impact. A preliminary assessment of potential significant effects of the proposed Project resulted in identification of the following impacts:

- Potential increase in air pollutant emissions (Air Quality);

- Potential increase in nuisance odor complaints associated with barge loading and the crude oil storage tanks (Air Quality);
- Potential increase in the risk of an oil spill that would affect marine water quality, marine life, and commercial and recreational fishing (Water Resources, Biological Resources);
- Increased vessel traffic impacts to marine mammals and turtles (Biological Resources);
- Potential increase in the risk of an oil spill that would affect terrestrial biological resources (Biological Resources); and
- Potential increase in the risk of an oil spill that would affect recreation in the vicinity of the proposed Project (Recreational Resources).

For the screening analysis, the technical and regulatory feasibility of various potential alternatives was assessed at a general level. Specific feasibility analyses are not needed for this purpose. The assessment of feasibility was directed toward reverse reason, that is, an attempt was made to identify anything about the alternative that would be infeasible on technical or regulatory grounds. The CEQA does not require elimination of a potential alternative based on cost of construction and operation/maintenance. For the proposed Project, those issues relate to:

- engineering feasibility and safety of implementation;
- potential adverse effects on the marine resources; and
- reasonableness when compared to other alternatives under consideration.

3.1.3 Summary of Screening Results

Potential alternatives were reviewed against the above criteria. A number of alternatives were eliminated based on their inability to meet most of the basic project objectives or that they were technically infeasible due to site-specific constraints. Those alternatives that were found to be technically feasible and consistent with the Applicant's objectives were reviewed to determine if the alternative had the potential to reduce the environmental impacts of the proposed Project.

Table 3-1 represents the evaluation and selection of potential alternatives to be addressed in the EIR. Those listed in the first column have been eliminated from further consideration (see rationale in Section 3.2, Alternatives Eliminated from Full Evaluation), and those in the second column are evaluated in detail in Section 4.0, Environmental Analysis, of this EIR and are described in detail below.

Table 3-1
Summary of Alternative Screening Results

Alternatives Eliminated from Consideration	Alternatives Evaluated in this EIR
Unit Train Crude Oil Transportation	No Project Alternative
Offshore Pipeline to Ventura County	Onshore pipeline to Las Flores Canyon and All American Pipeline as a potential transportation option under the No Project Alternative
Offshore Pipeline to Las Flores Canyon	Truck Transportation to Venoco Carpinteria Facility with subsequent pipeline transportation to Los Angeles Refineries as a potential transportation option under the No Project Alternative

3.2 ALTERNATIVES ELIMINATED FROM FULL EVALUATION

3.2.1 Unit Train Crude Oil Transportation

Under this alternative a unit train would transport oil from the Venoco Ellwood Onshore Facility (EOF) or Ellwood Marine Terminal (EMT) to refinery destinations via rail. The use of a unit train would require construction of a railroad spur to either the EOF or EMT and a crude oil loading rack. The use of a unit train would allow for crude oil transport to a variety of refinery destinations, but only those refineries that have the ability to accommodate unit trains. This would allow for nearly the same delivery flexibility as barge transportation associated with the EMT.

This alternative would avoid many of the impacts associated with the EMT related to accidental oil spills and impacts to the marine environment and associated resources. However, this alternative would result in substantial impacts to other issue areas, including noise, visual resources and recreation.

This alternative was found to be infeasible for a number of reasons, including the lack of access and/or available land at the EOF and EMT to accommodate a rail spur and crude oil loading rack, and incompatibility with surrounding land uses. While the EOF is immediately adjacent to a main rail line, there is not enough space at or around the facility to accommodate the necessary rail facilities. The EOF is bordered by a resort hotel complex on the west and a golf course on the east. Construction of a rail spur would result in blocked access to one or both facilities, which limits the feasibility of this alternative.

The EMT is further removed from the main rail line and does have some open space near the storage tanks. However, existing development between the EMT and main rail line precludes the construction of a rail spur. Therefore, this alternative is not technically feasible.

3.2.2 Offshore Pipeline to Ventura County

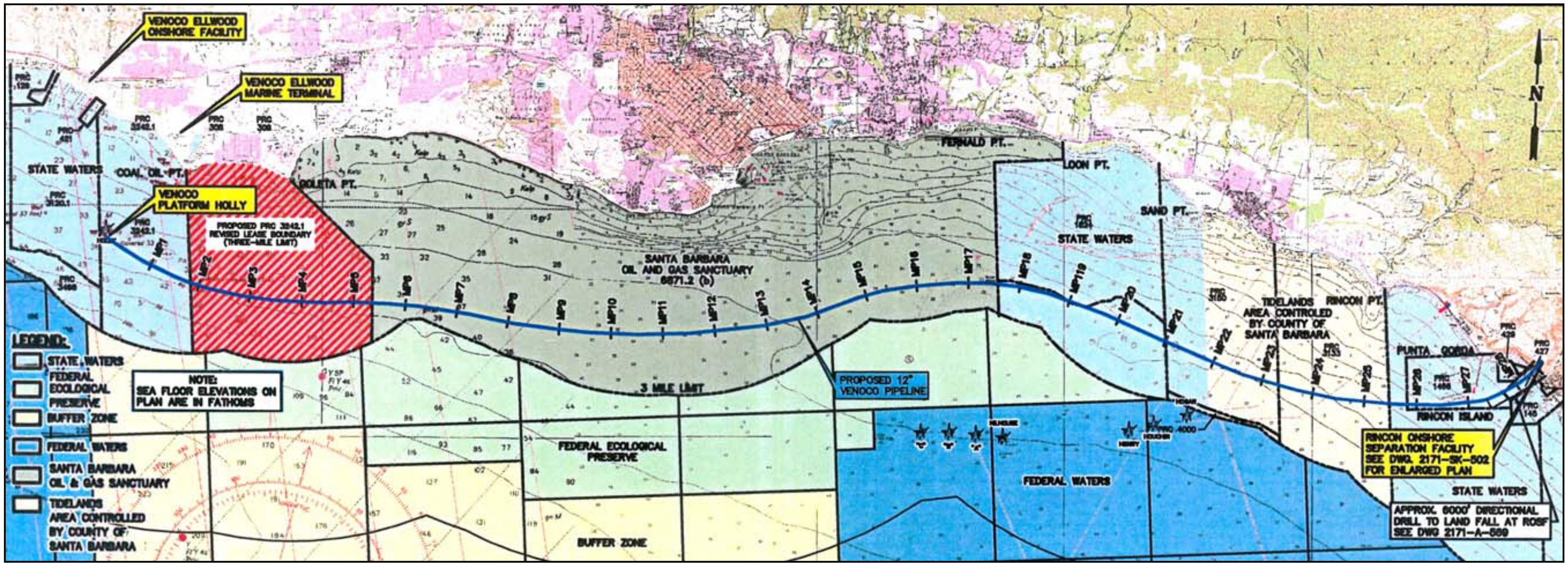
Construction of an offshore pipeline from Platform Holly to the Rincon Onshore Separation Facility (ROSF) in Ventura County (see Figure 3-1) was considered as an alternative to the proposed Project. The oil produced from Platform Holly would be transported to the ROSF through a new 12-inch (30-centimeter [cm]) diameter marine pipeline that would connect to the existing 22-inch (56-cm) diameter sales oil line. The installation and use of a pipeline would allow for the abandonment of the existing EMT and the discontinuance of barging.

As shown in Figure 3-1 the pipeline would follow a route from Platform Holly through State submerged land to the ROSF. This route is relatively flat and provides for the shortest length of pipe between Ellwood and the ROSF. It also avoids the Federal Ecological Preserve and the associated buffer zone in Federal waters.

The 12-inch (30-cm) pipeline would leave Platform Holly heading southeasterly in State Waters within Venoco's State Lease PRC 3242.1. The route would continue easterly through State submerged lands where it enters the parcel of State Tidelands managed by Santa Barbara County. Santa Barbara County was given control of this section of state land by virtue of a 1931 tidelands grant from the State Legislature.

The pipeline would leave the above-mentioned parcel and continue through ungranted State Tidelands where it would landfall through a 3,000-foot (914-meter [m]) directional drill. The directional drill would be made from the ROSF to an ocean outfall located approximately 1,000 feet (305 m) from shore in water depths ranging between 35 to 50 feet (11 to 15 m) below mean sea level. The proposed 12-inch (30-cm) pipeline would enter a pig receiver at the ROSF and be routed through a sales custody transfer meter and connected to the existing 22-inch (56-cm) sales oil pipeline.

Figure 3-1
Offshore Pipeline Alternative



Source; Venoco 2001.

This alternative was eliminated from further consideration in the EIR. First, this alternative does not avoid or substantially reduce many of the impacts associated with the proposed Project, mainly potential oil spills in the marine environment. The proposed pipeline also passes close to sensitive marine habitat. Finally, landfall would be near the town of La Conchita in an area that is known to be geologically unstable. This geologic instability could lead to a higher risk of pipeline failures and oil spills.

3.3 ALTERNATIVES EVALUATED IN EIR

3.3.1 No Project Alternative

Description

Under the No Project Alternative, Venoco's lease would not be renewed and the existing marine terminal would be subsequently decommissioned with its components abandoned in place, removed, or a combination thereof. The decommissioning of the marine terminal would be governed by an Abandonment and Restoration Plan, a copy of which has been submitted to the California State Lands Commission (CSLC), Santa Barbara County, and the city of Goleta as a component of Venoco’s “Development Plan Application for Ellwood Oil Pipeline Installation and Field Improvements” (Venoco 2005). Decommissioning of the facility is proposed to include the following actions:

- Magnetic survey of ocean bottom;
- Abandon and remove all EMT components above and below ground;
- Abandon in place the 10-inch pipeline (25-cm), ExxonMobil Pacific Line 96 (Line 96);
- Abandon in place certain portions of the 10-inch (25-cm) subsea cargo pipeline;
- Site Cleanup Verification - Side Scan Sonar and Remote Operated Vehicle (ROV) using video and Mesotech sonar equipment; and
- Following abandonment of the EMT components, a Phase I and Phase II site assessment will be conducted. Based on the results, a site closure plan would be prepared for approval by the appropriate agencies. In addition, a Restoration Erosion Control, and Restoration Program (RECRP) would be developed for approval.

Under the No Project Alternative, an alternative means of crude oil transportation would either need to be in place prior to decommissioning of the EMT or production at Platform Holly would cease. A consequence of the absence of the EMT and alternative crude oil transportation methods would be that the petroleum resources associated with the South Ellwood Field would be stranded, at least temporarily. It is more likely, however, that under the No Project Alternative, Venoco would pursue alternative means of traditional crude oil transportation such as truck transportation or a pipeline. Accordingly, the potential environmental impacts of the latter two alternative forms of crude oil transportation are described and analyzed in this EIR. For purposes of this EIR, it has been assumed that the No Project Alternative would result in a decommissioning schedule that would consider implementation of one of the described transportation options. Any future crude oil transportation option would be the subject of a subsequent application to the CSLC, city of Goleta, or Santa Barbara County, depending on the proposed option.

Required Agency Approvals

Agency approvals necessary under the No Project Alternative would include the agencies listed for each transportation option as well as the following:

- CSLC;
- California Coastal Commission;
- California Department of Fish and Game;
- Regional Water Quality Control Board; and
- Santa Barbara County.

3.3.2 Truck Transportation Option

Description

This option under the No Project Alternative would involve the use of trucks to transport crude oil from the Venoco EOF to a Venoco oil and gas processing facility in Carpinteria where it could be transported to Los Angeles area refineries via an existing crude oil pipeline (see Figure 3-2). Trucks from the EOF would enter Highway 101 at the nearby Hollister Avenue onramp and travel east on Highway 101 for approximately 25 miles (40 kilometers [km]) to Carpinteria. At Carpinteria, trucks would exit the highway at Bailard Avenue, and travel a short distance along Carpinteria Avenue to Dump Road and the Venoco Carpinteria Facility. The total one-way distance traveled by each truck would be approximately 27 miles (43 km).

The EMT tanks and equipment would not be utilized for this transportation option. The EMT and Line 96 would be abandoned (see EMT abandonment discussion above). Existing tanks at the EOF would be utilized for buffering of crude oil flows. Three tanks (the two existing crude oil tanks and the oily water tank), with a total capacity of 6,000 barrels (bbls) (954 m^3), could be available for storage at the EOF.

Under this transportation option, a truck loading rack would be constructed at the EOF to accommodate the necessary truck loading requirements. A truck unloading rack would be required at the Venoco Carpinteria Facility to transfer crude oil from the truck to an existing storage tank at the facility. The crude oil would be co-mingled with production from the Venoco Carpinteria Facility and transported via existing pipeline to Los Angeles area refineries.

Each tandem truck can hold approximately 160 bbls (25 m^3) of oil. At the current South Ellwood Field production rate of 4,000 barrels per day (BPD) (636 m^3/day) of oil, 25 roundtrip truck trips per day would be required to transport crude oil to Carpinteria. Under the permitted facility capacity of 13,000 BPD (2,067 m^3/day), 82 truck trips (164 one-way trips) per day would be required.

Required Agency Approvals

This transportation option would require approval by several local agencies, including:

- Santa Barbara County Fire Department;
- Santa Barbara County Air Pollution Control District (APCD);
- City of Goleta;
- City of Carpinteria;
- Carpinteria/Summerland Fire Department.

Venoco would also be required to update their South Ellwood Field Emergency Action Plan and Oil Spill Contingency Plan.

Figure 3-2
Proposed Truck Route

3.3.3 Pipeline Transportation Option

Description

This option under the No Project Alternative would involve the construction of an onshore 10-inch (25-cm) diameter crude oil pipeline from the EOF to the All American Pipeline (AAPL) at Las Flores Canyon (see Figure 3-3). The proposed 10-inch (25-cm) diameter pipeline would cross under Highway 101 near the EOF and run parallel to the north side of the highway for approximately 10 miles (16 km) to Las Flores Canyon. At Las Flores Canyon the pipeline would run a short distance up the canyon to the AAPL pipeline pump station that is located at the ExxonMobil Santa Ynez Unit (SYU) oil and gas processing facility. The Venoco Pipeline would tie in directly to the AAPL and would not utilize any of the ExxonMobil SYU storage tanks.

The EMT tanks and equipment would not be utilized for this option. The EMT and Line 96 would be abandoned (see EMT abandonment discussion above). Existing tanks at the EOF would be utilized for buffering of crude oil flows. Three tanks (the two existing crude oil tanks and the oily water tank), with a total capacity of 6,000 bbls (954 m^3), could be available for storage at the EOF.

The pipeline would be installed along Calle Real, which runs parallel to Highway 101 north of the highway. Since Calle Real does not run the entire length of the proposed pipeline route, the pipeline would also cross a few stretches of private ranch/agricultural roads that parallel Highway 101.

Pipeline construction

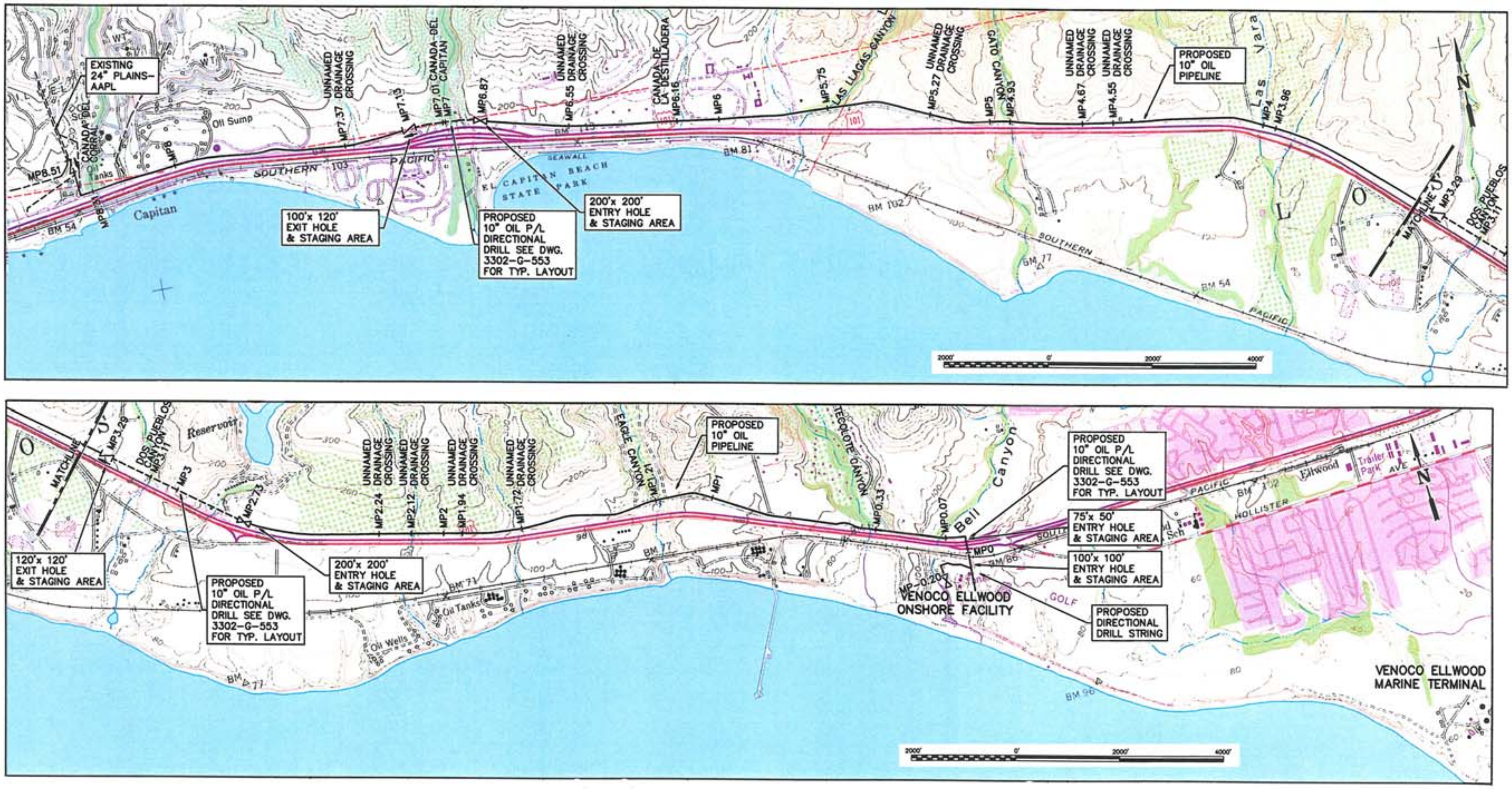
It was assumed that the pipeline would be constructed at an average speed of 500 feet (152 m) per day, as typically occurs in rural areas. Therefore, pipeline construction would take approximately 95 days with an additional 10 days for mobilization and 10 days for demobilization. The machinery required for construction is listed in Table 3-2. The peak day construction crew would consist of 40 persons, which include machinery operators, drivers, support personnel and management.

<u>Staging and Fabrication</u>

Pipeline construction operations would require staging and fabrication areas. Fabrication sites are linear in configuration and involve a wide variety of welding, testing, and inspection equipment. Sufficient area must be provided for these critical pipe fabrication and storage areas during the installation operations.

Figure 3-3

Proposed Pipeline Route



Source: adapted from Venoco 2005.

Table 3-2
Pipeline Construction Machinery

Construction Equipment	Number During Peak Day	Daily Usage	Daily Use, Hours	Duration, Days
Backhoe	2	0.8	8	95
Bending Machine	1	0.2	8	95
Compressor	1	0.4	8	95
Excavator/Dozer	1	0.4	8	95
Dump truck	2	0.3	8	95
Grader	1	0.5	8	95
Hydro Crane	1	0.2	8	95
Hydrotest Pump Unit	1	0.4	8	10
Jack and Bore Machine	0	0.6	8	5
Pickup Truck	3	0.3	8	95
Side Boom Truck	2	0.5	8	95
Tractor/Trailer	1	0.4	8	95
Utility Tool Truck	2	0.2	8	95
Vacuum Truck	1	0.2	8	95
Water truck	1	0.3	8	95
Welding truck	4	0.5	8	95

Typically, pipe is trucked to the site and a boom crane is used to store pipe in a rack. Pipe is normally shipped in pre-coated 80-foot (24 m) segments ready for welding. The pipe staging area that would be used for the pipeline construction would likely be the EOF.

The major material component of the Project would be pipe. It would be stored at a vendor's coating yard, EOF, or existing storage yards until it is delivered to the pipeline route as necessary.

During all phases of construction, refueling and lubrication of construction equipment would occur at the contractors' staging yards, the EOF, or onsite. Equipment would be regularly checked for leakage.

<u>Transport</u>

Most of the heavy construction equipment would be delivered to the EOF site pipe delivery/staging yard on lowboy trucks or trailers. Access to the site would be from existing access roads and driveways. Mobile cranes and dump trucks would be driven in from local contractors' yards. Construction equipment would be left overnight at the EOF. All equipment would be lubricated, refueled and repaired by the contractor or local servicing companies.

All construction materials would proceed to the construction spread by truck on existing roadways. The new pipe would be 10-inch (25-cm) outside diameter, 0.500-inch (1.3-cm) wall thickness pipe. A typical truckload of approximately 47,000 pounds (21,319 kilograms [kg]) would accommodate 18 joints of pipe or approximately 718 feet (219 m) of pipe. A total of 74 one way truckloads would be required to transport new 10-inch (25-cm) pipe to the EOF staging area.

<u>Clearing and Grading the Right-of-Way (ROW)</u>

Grading and cut-and-fill excavation would be performed in such a way as to minimize effects on natural drainage and slope stability. Upon completion of construction, the ground surface would be restored to the original grade. Some excavation and grading outside the pipe ditch may be performed to increase the stability and decrease the gradient of unstable slopes. In designated areas, top soil would be segregated from other ditch spoil and replaced as part of surface restoration. Clearing would include the removal of above ground obstacles to the work such as trees, brush, crops, and boulders. Clearing also would include removal of tree stumps and roots in the ditch line that could interfere with operation of the ditching machine. Removal of only the trees, brush, and crops necessary for construction and maintenance would be permitted. The minimum feasible amount of vegetation would be removed, and the removed vegetation would not include threatened or endangered species.

Where fences are encountered along the ROW, adequate bracing would be installed at each edge of the ROW prior to cutting the wires and installing temporary gates. Upon completion of construction, the fence would be reconstructed to its original condition or better.

An area 25 ft (7.6 m) in width, along a frontage, would be needed on each side of roads, railroads and minor water crossings that require boring. Additional storage areas for equipment, pipe, and other materials would be acquired through private permission or temporary use permits.

The pipeline ditch would be open for as little time as practical with stringing usually preceding ditching. Pipe-stringing trucks would be used to transport the pipe in 40-foot (12-m) to 80-foot (24-m) lengths from a shipment point or storage yards to the pipeline

ROW. Side booms would carry the line pipe from the stringing trucks and lay it end to end beside the ditch line for future line-up and welding. Turnaround areas for stringing trucks would be provided by using existing roads.

<u>Ditching</u>

Once the ROW has been prepared, ditching operations would begin. Ditching would include all excavation work required to provide a ditch of the specified dimensions and depth of pipe cover. A standard dimension ditch, from a minimum of about 3 feet (1 m) to a maximum of about 4 feet (1.2 m) wide, would be centered on a line near the edge of the 12-foot (3.6-m) wide ROW, thus providing about 8 feet (2.4 m) of working space and an area in which to place ditch spoil. A standard dimension ditch would be excavated mechanically with ditching machines. In areas where loose or unconsolidated rock is encountered, the ditch would be excavated using backhoes and clam shell buckets. An exception to the mechanical excavation would be hand-digging to locate buried utilities, such as other pipelines and cables. Based on the geology traversed by the pipeline route, no blasting would be expected.

The depth of the ditch would vary with the conditions encountered. Normal pipeline construction places lines at a depth of 48 inches to 60 inches (122 cm to 152 cm) to the top of pipe depending on the location. When crossing over and under other pipelines, cables, etc., a minimum clearance of 12 inches (36 cm) would be standard. The 12-inch (36-cm) clearance may be reduced if special precautions are taken to prevent interference. Rock excavation would require that at least 18 inches (46 cm) of cover be placed over the pipe. These depths meet or exceed the California State Fire Marshal requirements per the U.S. Department of Transportation (DOT) and the Code of Federal Regulations (CFR) Title 49, Part 195, Transportation of Liquids by Pipeline.

Occasionally, the ditch would be excavated to greater depths. For instance, when the pipeline traverses areas for which there are definite plans to level the land for irrigation or other purposes, the pipe would be buried at a depth that would permit the land to be leveled. When crossing canals, borrow ditches, or irrigation ditches that are dredged to maintain depth, the pipeline ditch would be excavated to a depth that would permit safe dredging operations. At railroad and road crossings, the depth of the pipe would conform to appropriate regulations.

<u>Pipe Coating</u>

State of the industry pipeline coating would be applied at the mill before delivery to the construction site. However, field coating would be necessary on all field weld joints made at the site in order to provide a continuous coating along the pipeline. After the pipe has been welded and radiographically inspected (x-rayed), heat shrink polyethylene sleeves would also be used or alternatively, polyken tape and tape primer may be used. The use of heat shrinkable products or shrink sleeves is the most dominant method used to protect joints worldwide due to:

- design flexibility and compatibility with pipeline conditions and pipe coatings, and
- high reliability and superior service performance.

Polyethylene heat shrinkable sleeves are used as the primary method to protect pipe joints from corrosion. These sleeves are wrapped around the pipe joints where there is exposed unpainted metal. The sleeves are then heated using a propane torch to the proper installation temperature. The sleeves are made with a thermochromic pigment that changes color when the proper installation temperature is reached, making installation fast and easy. Upon heating, the sleeve contracts, encapsulating the joint and at the same time squeezing sealant into all surface irregularities forming a tight seal. This seal is very effective at protecting the joint from moisture and air ingress to the pipe surface.

Protecting the pipe from moisture and air would help prevent the pipe from corroding. The prevention of corrosion would in turn prevent any cracks, breaks, and leaks caused by the corrosion of the pipe. The sleeves are also engineered to withstand the effects of temperature cycling, soil stress, hydrostatic pressure and chemical attack.

Shrink sleeves are very reliable in preventing moisture from contacting pipe and have been used for over thirty years. As technology has increased in reliability and durability, so has the shrink sleeve. Quality control ensures that raw materials, in-process materials and the finished products are subjected to exhaustive testing to comply with strict specifications. Quality assurance procedures permit traceability of every component throughout the manufacturing process. This ensures that the shrink sleeves would be compliant with all applicable safety and protection requirements.

A “holiday detector” would be used to locate any coating discontinuities (such as thinning, or other mechanical damage) that could permit moisture to reach the pipe.

The testing device develops an electrical potential between the pipe and an electrode in contact with the outside of the coating or ground. Pinholes in the coating of microscopic size can be located using the electrical detector. All coated pipe, including field joints, fittings, and bends would be tested.

Testing and Inspection

All field welding would be performed by qualified welders to Venoco's specifications and in accordance with all applicable ordinances, rules, and regulations, including American Petroleum Institute (API) 1104 (Standard for Welding Pipe Lines and Related Facilities) and the rules and regulations of the DOT found in 49 CFR (Part 195 for liquid pipelines). As a safety precaution, a minimum of two 20-pound (9-kg) dry chemical unit fire extinguishers would accompany each welding station.

All welds (100 percent) would be visually and radiographically inspected for exceeding the 10 percent inspection requirement found in 49 CFR Part 195. Radiographs would be recorded and interpreted for acceptability according to requirements of API 1104. All rejected welds would be repaired or replaced as necessary and re-radiographed. The x-ray reports as well as records indicating the location of welds would be kept on file for the life of the pipeline.

In addition to standard mill testing of all pipe and fittings, hydrostatic testing would be performed after construction and prior to startup. Federal DOT regulations (49 CFR Part 195) mandate hydrostatic testing of new, cathodically protected oil pipelines prior to placing the line into operation.

The hydrostatic test involves filling the pipeline with water and increasing pressure to a predetermined level. This pressure level would be maintained at least 1.25 times the pipeline maximum operating pressure for a minimum of 8 hours. Such tests are designed to prove that the pipe, fittings, and weld sections would maintain mechanical integrity without failure or leakage under normal operating pressure.

Permanent records would be kept on each hydrostatic test. These records would contain the exact location of the test segment, the elevation profile, a description of the facility, and continuous pressure and temperature of the line throughout the test. Deadweight testers would be used to verify the accuracy of pressure-recording devices and charts during the test, as required by 49 CFR Part 195.

Water would be pumped into the pipeline using existing pumps at the EOF. A high-pressure portable test pump would be used to bring the pipeline up to test pressure.

The test pressure and pipeline temperature would be continuously monitored for any changes for a minimum 8-hour period, in accordance with Federal and State regulations.

At the conclusion of the test, water in the pipeline would be bled back into the produced water treatment system at the EOF. Nitrogen gas would be pumped into the pipeline from the AAPL receiving station to displace the seawater back to the EOF. Pigs would be utilized on the 10-inch (25-cm) pipeline to effect total displacement of the water with nitrogen. The pipeline would be left packed with nitrogen at low pressure to prevent corrosion until the pipeline is placed into service.

Lowering and Tying-In

The pipe would be lifted and lowered into the ditch by two or more side-boom tractors spaced so that the weight of unsupported pipe would not cause buckling or other damage. Cradles with rubber rollers or padded slings would be used so the tractors can lower-in the pipe as they travel along the ditch without damage.

Tie-in welds would be required whenever there is a break in the continuous operation of the main-line pipe crews. This would occur at road crossings, water crossings, block valves, and other special locations. Tie-in welds are usually made in the ditch at the final elevation and each weld requires pipe handling for line-up, cutting to exact length, pipe cleaning and coating, and backfilling in addition to normal welding and weld inspection.

Backfilling

A variety of backfilling procedures would be used to perform the work effectively and economically and to comply with specifications regarding protection of pipe and coatings. Motor graders, angle dozers, and modern backfill machines would be used to move dirt from the spoil bank to the ditch. Where specified, the backfilled earth would be compacted in accordance with the specifications of various interested agencies to avoid later settling. In certain areas where damage might occur to the pipe coating, protection would be provided by padding the ditch with Rockguard (protective coating), clean sand, or earth backfill.

Special Construction Techniques

In most cases, roadbeds supporting roadways or railroads would be crossed by boring a hole horizontally from one side to the other. The cutting head of the boring auger would be slightly larger than the casing pipe or line pipe. The pipe would be installed immediately behind the cutting head as it advances. Bore and reception pits are necessary. Bore pit dimensions would typically be 10 feet wide by 15 feet long by 8 feet deep (3 m by 5 m by 2 m). Steel casing would be used to encase road crossings where required by Federal, State, local, or railroad authorities. Steel casings would be utilized for crossing rail lines and Highway 101.

<u>Receiving, Custody and Metering Station Construction</u>

Work at the AAPL receiving station would take approximately two months. Work required to construct the AAPL receiving station includes:

- Civil work including construction of equipment foundations. New foundations would be constructed to support above ground piping after the pipe is installed. Piping work, including installation of a new pig receiver, custody transfer oil meters, a fixed meter prover, connection to the existing AAPL pipeline, and associated support utilities for lighting, power and monitoring and controls.

- Electrical crews would install new conduits and wires for Supervisory Control and Data Acquisition (SCADA) System pipeline leak detection and instrumentation at the AAPL.

Pipeline Operation and Maintenance

<u>System Operation</u>

The proposed pipeline would be monitored and operated from the EOF. The EOF would provide for continuous monitoring 24 hours per day. No additional positions to the existing staff would be required as a result of this transportation option.

<u>System Control, Operation and Safety Features</u>

The proposed computerized system of pipeline communications and system control is referred to as the SCADA System. The function of this system is to send instructions to and receive information from Programmable Logic Controllers (PLCs) located at the EOF and the AAPL station for use by automatic controls, automatic safety systems and operators in monitoring pipeline operations. The Master Station or Control Center would be located at the EOF. The Master Station would originate remote control commands and receive status and alarm data from the PLCs. The PLCs would receive and execute valid commands from the Master Station and transmit alarm and status information back to the Master Station. The SCADA computer system would be programmed to continuously scan for leaks and annunciate alarms.

A number of backup systems and redundant equipment would be used to ensure the proper function of the SCADA System. These systems include backup computers and peripheral equipment that would be located at the Master Station to increase reliability and allow for maintenance and repair of control equipment without disruption of normal pipeline supervision and control. In the case of a short power outage, an uninterrupted power supply (UPS) would supply the central control facility for approximately four hours.

The Master Station would communicate with the PLC at the EOF through a hard-wired connection. Communication to the AAPL PLC would be accomplished through leased telephone circuits with a radio backup. In the event of a failure in the primary and backup communication systems, an operator, with company provided handheld communications radio and telephone, would be dispatched to the AAPL station.

Operators at the EOF Control Center would have the ability to initiate and terminate flow into the pipeline from the EOF, start and stop pumps, as well as monitor line pressures, temperatures, flow rates, and operate inlet and outlet valves. Any equipment failure and operation alarms would be transmitted to the operator for corrective action. A deviation in input and output volume or pressure would trigger such an alarm.

The Oil Shipping Pumps would be equipped with various safety devices such as pressure sensing devices, and electrical current and temperature measuring devices to assure reliable and safe operation. The pipeline would be protected from over pressure by three levels of protections: pressure control valves, high-pressure shutdown switches, and pressure relief valves. The computerized SCADA System constantly gathers operational data from the critical sources throughout the system and automatically adjusts the pressure and flow rate of the pipeline to provide for safe operation of the pipeline. The SCADA System also provides for continuous leak detection monitoring and displays that allow operators to see real time operating data for the pipeline.

The pipeline leak detection system to be installed would consist of three components: (1) volumetric balance, (2) flow difference monitoring, and (3) pressure/flow monitoring. The system would be able to detect a leak as small as 1 percent of flow. At the approximate maximum flow rate of 13,000 BPD (2,067 m^3/day), this would result in the ability to detect a leak as small as 5.4 bbls (0.9 m^3) in one hour or 0.09 bbl (0.014 m^3) in one minute.

The volumetric balance component of the SCADA System, in addition to using metered input and output volumes in its calculations, takes into account the changes in real pipeline conditions represented by net volume changes in pipeline capacity and is calculated once per minute. The volumetric change is calculated and then rolled into six integration periods to determine system loss. Each integration period is compared against pre-defined limits so that when a violation of a limit occurs, the operator is alerted through an alarm.

Flow difference monitoring consists of checking for unexpected differences in pipeline flow into the pipeline at the EOF and out of the pipeline at the AAPL. If the total flow out of the pipeline at the AAPL minus the total flow into the pipeline at the EOF is greater than a predetermined maximum variation, an alarm is issued to the operator and the Control Center.

The third component of the SCADA System is the pressure/flow monitoring to check for rapid changes in the pressure and/or flow rate on the pipeline. Pressure and flow variations limits are configured for use in comparing the actual telemetered data with the expected values. Running averages are maintained for these sampled pressure and flow rates over pre-defined periods of time. The system projects the next sample by calculating the slope of the current deviations using the period as the base and a configurable number of samples up to a maximum of 15. If the resultant value falls outside a pre-defined limit, a second check is performed after the next sample against a different pre-defined limit. If this limit is also violated, a pressure deviation alarm is generated.

If both pressure limits are violated, flow rate deviation processing begins and continues for the configured period of time. Flow rate deviations are calculated using the same technique as for pressure deviations. Flow rate processing only takes place when there is an active pressure violation.

<u>System Inspection and Maintenance</u>

Visual Inspection

The pipeline route would be visually inspected at least once each week by line rider patrol, which is more frequent than required by DOT requirements (49 CFR Part 195 requires visual inspection 26 times per year) to spot third-party construction or other factors that might threaten the integrity of the pipeline. Additionally, inspection of highway, utility, and pipeline crossing locations would be conducted in accordance with State and Federal regulations. Pipe protection level would be inspected annually at all test locations, quarterly at control points, and more than quarterly at cathodic protection systems to ensure corrosion control.

Pigging

Pigs or scrapers are devices inserted into the pipeline at pig launcher points and retrieved at receiving points called pig receivers or scraper traps. Pigs are used to clean and/or inspect the pipeline.

"Smart" pigs are devices used to inspect and record the condition of the pipe. Smart pigs detect where corrosion or other damage has affected the wall thickness or shape. The pipeline would be designed to be capable of running smart pigs in accordance with DOT standards.

Pipeline Hydrostatic Testing

A five-year hydrostatic test is required by DOT for Hazardous Liquid Pipelines per 49 CFR Part 195. The hydrostatic test is identical to the test performed for newly constructed pipeline, except that the test period is reduced from 8 hours to 4 hours. The test is performed to prove that the pipe, fittings, and weld sections can continue to maintain mechanical integrity without failure or leak under test pressure conditions.

Valve Inspection

Block valves are cycled and inspected twice annually, not to exceed seven months between inspections, to ensure proper operation (per 49 CFR 195.420).

Cathodic Protection System Testing

Several procedures are used to monitor and test the effectiveness of the cathodic protection system installed on pipelines. The cathodic protection system consists of power sources called rectifiers, buried anodes, and test stations along the pipeline. For the proposed pipeline, only two rectifiers would be necessary, and would be installed at the EOF and at the AAPL. The rectifiers would be checked weekly to ensure that they are operating properly. Quarterly, voltage and current readings are recorded for the rectifiers and voltage readings at critical test stations are measured and recorded. Annually, a complete pipeline survey of the voltage readings at all test stations are measured and recorded. If the data indicate that potential problem areas exist on the pipeline, voltage readings are taken all along the suspect areas using a technique called a close interval survey. Adjustments are made to the system, as required, when test data indicate that voltage levels are outside of the design limits.

Emergency Response

Individual Oil Spill Response Plans (OSRP) have been prepared for review and approval by appropriate Federal, State, and local agencies (including the California Department of Fish and Game, Office of Spill Prevention and Response) for each company's respective pipelines. An OSRP is required under State and Federal regulations (SB 2040 and 40 CFR 300, the Hazardous Substances Pollution Contingency Plan). The OSRP provides a finalized list of emergency service providers. Venoco has also prepared an Emergency Action Plan (EAP) to specify measures to be taken in emergency scenarios for its existing facilities. These documents identify the responsible parties for the Incident Command System and the supporting organizations/agencies. The OSRPs and EAP would be updated to reflect the new EOF to AAPL pipeline.

Venoco has a contractual agreement with a regional spill response cooperative (Clean Seas) that serves as the emergency response contractor with primary responsibility for containment, cleanup, and health and safety. The OSRP lists third-party contractors providing manpower and equipment such as vacuum trucks, boats, oil skimmers, absorbent and skirted booms, dump trucks, portable tanks, absorbent materials, dispersants, steam cleaners, hydroblasters, cranes, and forklifts. These contractors are located in the Tri-County regional area. In addition, operations personnel are trained in the Incident Command System and oil spill containment and cleanup procedures.

Abandonment and Decommissioning

The expected operational life of the pipeline would be at least 50 years. This time is based on the expected economic obsolescence of the system. Current cathodic protection systems and internal inspection techniques can preserve the life of a petroleum pipeline for a longer time period.

The decommissioning process would be subject to appropriate local, State, and Federal regulations that are in effect at the time of abandonment. As required by Federal and State laws, the pipeline operator would be liable for cleanup and remediation of any potential contamination that could have resulted from the operation of the pipeline.

Required Agency Approvals

This transportation option would require approval by several Federal, State and local agencies, including:

- U.S. Department of Transportation. Office of Pipeline Safety;
- U.S. Army Corps of Engineers;
- U.S. Fish and Wildlife Service;
- California State Fire Marshall;
- California Department of Transportation;
- California Coastal Commission
- California Department of Fish and Game;
- Santa Barbara County;
- Santa Barbara County APCD; and
- City of Goleta.

Venoco would also be required to update their South Ellwood Field Emergency Action Plan and Oil Spill Contingency Plan.